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Concentrated Solar Power Solar Tower with Oversized Solar Field and Molten Salt Thermal Energy Storage Working at an Annual Average Capacity Factor of 95% in NEOM City

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Herein, a design for a concentrated solar power (CSP) plant solar tower (ST) with thermal energy storage (TES) by molten salt (MS) in NEOM city, a 100% renewable energy planned development, is presented. The novelty of the design is the oversized solar field, as well as the TES, to produce nearly constant power output every day of the year, with minimal reductions only in the winter months. A 95% annual average capacity factor is estimated to be delivered by this ST plant at a levelized cost of electricity (LCOE) of 7.84 c kWh^{-1}. The CSP ST with 16 h of TES by MS is the best opportunity to deliver cost-effective, fully dispatchable, reliable renewable energy, for both the economy and the environment. Other renewable energy options such as solar photovoltaic (PV) and wind may offer a lower LCOE even below 5 c kWh^{-1}, but once battery storage is factored for dispatchability, the real cost increases by 14 c kWh^{-1}. The proposed technology may deliver most of the electricity needed by NEOM city, with solar PV and wind plus batteries used for peak demand and to compensate for residual variability.

1. Introduction

Renewable energy targets of 50% or even 100% energy share based on wind and solar are desirable; however, current worldwide wind and solar installations are not yet showing a clear pathway to reach these targets.[1,2] This is mainly due to the variability and unpredictability of the wind and solar energy resources, which would require massive external energy storage to stabilize the grid demand.[3,4] This is currently economically and environmentally unaffordable. The intermittency and unpredictability of the solar and wind resources necessitate massive energy storage. A revised levelized cost of electricity (LCOE) should be considered.[3,4,7–10] NEOM city is a location along the Red Sea coast of the Kingdom of Saudi Arabia where a 100% renewable energy city is planned. The full energy demand is deemed to be based on wind and solar energy resources only. The LCOE from solar photovoltaic (PV) power plants may reach low values below 5 c kWh^{-1} without any storage,[10] similar to solar PV costs that are obtainable by wind as wind resources are less favorable than solar for the specific area of NEOM city. When storage is added to PV plants, the Li-ion batteries are charged and discharged at a fraction of the nominal power, with a lifespan much shorter than the lifespan of the solar plants, requiring replacement. The additional battery storage needed adds to the cost of electricity of at least 14 c kWh^{-1}.[11]

In the real world, the latest 50 MW power, 64.5 MWh of energy, lithium-ion battery extension in Hornsdale had a cost of 71 million AU$, or 50 million US$.[12] As solar PV is only available on average 12 h a day, and it is unavailable 12 h a day, by considering 30–80% state-of-charge cycles per day, over 30 years, this is a cost for storing and releasing energy of $50 \times 10^6/(32.25 \times 365 \times 30) = 0.14$ US $ kWh^{-1}. Now, this estimation is very optimistic, as lithium-ion batteries do not last 30 years working in the harsh conditions of Saudi Arabia characterized by sand, dust, and extreme temperatures. Thus, the 14 c kWh^{-1} may be 28 c kWh.

It must be mentioned that recent contracts in the United States (e.g., LADWP) have achieved a claimed levelized solar PV + storage (52% of daily PV energy) power purchase agreement (PPA) price of ≈3.8 c kWh^{-1}. Even after discounting for the subsidy (≈30%), the unsubsidized PPA price is 5 c kWh^{-1}. PPAs have absolutely no value as they are not indications of costs then really delivered. For example, Crescent Dunes has been shut down after less than 4 years of operation, producing over 4 years less than the electricity promised in a single year.[13] A PPA was signed for the exactly same badly operating plant to be built in Port Augusta[14] expecting the impossible dispatchable electricity production of 6 c kWh^{-1}. No investor believed these numbers, and the power plant was never built.

It is a fundamental flaw of many analyses to misinterpret price for the cost. Cost is the expense incurred for making a product or

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service. Price is the amount a customer is willing (or forced) to pay for a product or service. A PPA is by no way an indicator of cost, especially for renewable energy products. It is also a major issue to keep private production data, as well as data of costs to produce, rectify, repair, and maintain power plants, with very few exceptions worth mentioning.

Here we present the design of a concentrated solar power (CSP) plant solar tower (ST) with thermal energy storage (TES) by molten salt for NEOM city. Simulations are performed using the National Renewable Energy Laboratory (NREL) System Advisor Model (SAM) software.[15] This software generally provides a smaller LCOE for the financial and operational analysis of a CSP plant ST versus a parabolic trough (PT) or linear Fresnel. Analyses of the performance of utility-scale solar thermal power projects in which actual performance and cost are compared to the predicted performance and the projected cost have been recently added to the literature.[7,16] The SAM software has been recently validated using the actual monthly electricity production data of the three largest CSP PT plants in the world, Solana, Genesis, and Mojave.[17] Financial forecasts using SAM may be unreliable. This is however the best tool currently available for forecasts.

NEOM city is a planned city in the Tabuk Province, in the northwest of Saudi Arabia. The site is along the Red Sea and covers a total area of 26 500 km^2 stretching 460 km along the coast. The project has an estimated cost of US$500 billion. NEOM city will be home and workplace for more than a million people from around the world, building a new model for sustainable living, working, and prospering. The city is planned to be completely powered by renewable energy sources.

Generic resource maps for the annual average wind speed (7.43 m s^{-1} at 50 m) and annual average power density (≈600 W m^{-2}) indicate a moderate wind energy resource[18] broadly corresponding to a class 5 wind region, with however larger potential along the coast and off-shore. For what concerns solar resources, this is quite a good site, with (per year) specific solar PV power output of 1995 kWh kWp^{-1}, direct normal irradiation (DNI) of 2672 kWh m^{-2}, global horizontal irradiation (GHI) of 2345 kWh m^{-2}, diffuse horizontal irradiation (DIF) of 575 kWh m^{-2}, and global tilted irradiation at an optimum angle (GTI Opta) of 2591 kWh m^{-2}.[19] The resources both wind and solar are characterized by a large high-frequency coefficient of variability, the ratio of the standard deviation to the mean, largely more than 1. The wind is unpredictable, and the solar resource is intermittent. Conversely, a grid demand is characterized by a small coefficient of variability, one order of magnitude smaller. Even if affected by the weather, the grid demand is not determined by the weather, and relevant also after sunset. Furthermore, the peaks and valleys of the grid demand are generally not phased with the peak and valley of the resource.

We consider the specific solar irradiance data retrieved from elsewhere[20] and shown in **Figure 1**. The data are available every hour for the standard year; that is, this case is the average over the years 2004–2018. The mean DNI for each month is provided with its standard deviation shown as standard error and the maximum and minimum daily DNI. Its coefficient of variability shows the large resource variability for solar energy. In the management of a renewable energy–only grid, the forecast of energy production has to cover many hours with a high-frequency resolution of 1 min or less, which may be extremely challenging as past measurements do not generally have the quality and resolution needed.

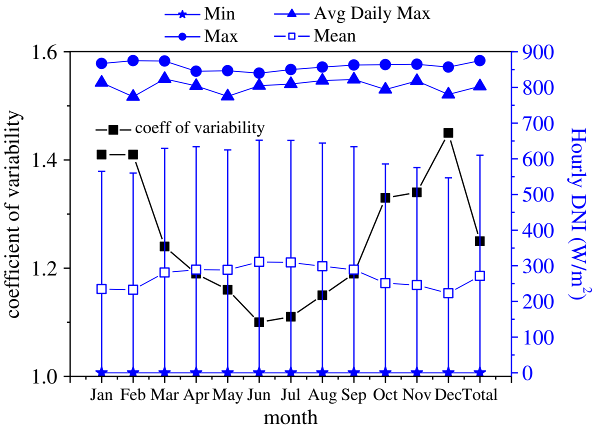


Figure 1. Sun resources in NEOM city 28°17′15″ N and 34°50′42″ E: coefficient of variability (black squares), DNI mean (blue open squares) DNI average daily max (triangles), DNI average max (circle).

CSP with TES is the only renewable energy technology that permits dispatchability without the need for external energy storage by a battery[21–26] because thermal energy is stored instead. Molten salt TES is environmentally and economically superior to battery storage. Therefore, these facilities may deliver an output much closer to power on demand if compared to wind and solar PV,[3,5] which require electrical energy storage using currently available technologies. The theoretically best CSP plant to consider is the CSP ST with molten salt TES. This technology generates solar power by concentrating sunlight onto a small area.[22,26] The solar field is a large array of many dual-axis heliostats concentrating sunlight onto the central receiver atop a tall tower. The highly concentrated light warms up the molten salt to the hot tank. Steam is produced in a heat exchanger with the molten salt. This steam then expands in a turbine to generate electricity.[27,28] The condenser is air cooled, evaporative, or hybrid. Close to the sea, a saltwater once-through condenser may be used with some efficiency benefits. In terms of the annual average capacity factor (CF) for a given size of the turbine, the ST design is theoretically superior to the more consolidated, widespread, much simpler, and reliable PT design, or also the linear Fresnel, which is a compromise between performance and costs.

The 2020 NREL Annual Technology Baseline (ATB)[29] considers as the reference CSP technology a ST with 10 h of molten salt TES by two tanks exemplified in the Crescent Dunes plant,[13,30] which is even less sophisticated than the more than 10 years old Gemsolar technology,[31] a project started in 2007.

The 110 MW Crescent Dunes has a solar field characterized by 10 347 heliostats of aperture area 115.7 m^2 around a tower of height 195 m. The receiver temperature is 565 °C. The hours of TES are 10. This is 10 911 m^2 of solar field per megawatt of turbine power. The solar resource is 2685 kWh m^{-2} year^{-1}. The solar input per megawatt of power is 28 915 162 kWh year^{-1}. The 20 MW Gemasolar had 2650 heliostats of aperture area 120 m^2. This is 15 900 m^2 of solar field per megawatt of turbine power. The solar resource is 2100 kWh m^{-2} year^{-1}. The solar input per megawatt of power is 33 390 000 kWh year^{-1}. Thermal storage is 15 h. The receiver temperature is 565 °C.

The reduced solar input per megawatt of power and the reduced TES, and unfortunately the use of substandard components, were part of the absurd goal to compete price-wise with solar PV and wind without accounting for dispatchability. As a result, Crescent Dunes newer worked out as expected, producing in 4 years of life before being prematurely shut down less than the electricity produced in a single year.

It is only recently that the scientific community has understood that a renewable energy–only grid wind and solar PV needs external energy storage by batteries that are simply unaffordable. It is therefore only recently that the scientific community has started considering much higher solar input per megawatt of power and more hours of TES for better dispatchability or continuous operation.

Unnoticed so far, exploring, in the default model of SAM[15] for a CSP ST with TES for a given turbine power, the opportunity to change the specific size of the solar field versus the suggested optimum, and the number of hours of TES versus the canonical 10, permits us 1) to improve the annual average CF; (2) to reduce the standard deviation of the CF with hourly resolution; and 3) to reduce the LCOE, that is, improve the design under every possible criterion.

The design of an ST plant is proposed targeting a high CF, and a low standard deviation of the CF, for a continuous supply of energy, at affordable costs, in NEOM city.

2. Experimental Section

The SAM model is very well known as this is the leading software tool for CSP plants.[15] Details of SAM for CSP applications are provided elsewhere.[32] All the information about the cost model is available in ref. [33] and listed references. The CSP ST with TES costs of SAM is consistent with the latest estimations of the NREL ATB.[29] The system costs are the latest proposed by NREL and provided in SAM. The LCOE computation includes technical (energy production, degradation) as well as financial parameters (cost of plant, operation and maintenance, taxes, financing, life span).[33] The specific cost data are provided in ref. [33]. Modeling details are provided in ref. [34]. Applications are detailed in ref. [34] and listed references. Validation is detailed in ref. [35] and listed references. All the mathematical equations are presented in the SAM manuals, and the publications referenced in refs. [33–35]. SAM is very well known in the CSP scientific community.

SAM's CSP models are available for several different types of CSP systems, namely, 1) a parabolic trough with an oil or salt heat transfer fluid, without thermal storage; 2) a parabolic trough with an oil or salt heat transfer fluid, with thermal storage; 3) an ST with molten salt storage; 4) an ST with direct steam; 5) a linear Fresnel with molten salt and storage; 6) a linear Fresnel with direct steam and no storage; and 7) a dish Stirling with no storage.

There is a consensus among the scientific community that an ST with molten salt TES is the best technology. This has been the reference technology in the NREL ATB for CSP for many years. While linear Fresnel developments are rare around the world, and dish Stirling plants are even less popular, it must be mentioned that the much simpler and reliable parabolic trough is still much more widespread than the power tower. However, in a parabolic trough increasing the size of the solar field dramatically increases the thermal inertia of the system (the thermal inertia of the system increases by increasing the size of the solar field). This is not the case with the power tower. In addition, the maximum temperature out of the solar field in the parabolic trough is typically limited to less than 400 °C, whereas this is 565 °C in current-technology power towers and it may be much larger in near-future advanced STs.

Figure 2 shows at the top left a scheme of the CSP ST with the TES plant. The heliostat field is circular, with the heliostats placed around the central tower (top, right). At the bottom is a satellite view (from Google Maps) of the Crescent Dunes plant, with clear evidence of the central tower, the power block, and the two tanks.

The model is composed of a location and resource section, where the typical year data of Tabuk is imported and selected. The system design, heliostat design, power cycle, and TES parameters are those typical of the NREL ATB reference CSP ST with TES design (i.e., Crescent Dunes) but with a variable number of heliostats and small changes to tower height and receiver properties, and much larger hours of TES. Cost and financial parameters are taken as the default SAM parameters, apart from project tax and insurance rates, which are different. The hot tank heat transfer fluid has a temperature of 574 °C.

For a 100 MW net power plant, the heliostat field is considered to be 10 000–20 000 two-axis tracking heliostats 12.2 × 12.2 m^2. The tower has a height of 200 m. The ST has a 20.66 m receiver height and a 17 m receiver diameter. The heat transfer fluid is salt 60% $NaNO_3$ and 40% KNO_3. The power cycle has steam at 574 °C and 100 bar. The condenser is air cooled, evaporative, or hybrid. Evaporative cooling permits better results, but at the cost of water consumption. Saudi Arabia has no lake or river and thus freshwater use is a concern. Comparison of the air-cooled and evaporative cooling condenser is proposed hereafter. The reference cycle thermal efficiency is $\eta = 41.2\%$. Molten salt is solar salt. Energy storage is 16 h. The advantage of using a larger number of hours of TES was already known at the time of Gemasolar.

There is no mention in this work of a load profile or the load factor. In the simulations, the CSP plant with TES is used for baseload operation, which is one of the opportunities offered by CSP with TES. Opposite to solar PV, CSP with TES can also be specialized for a different operating profile, such as generation after sunset, to complement generation during daylight time by the much cheaper solar PV. As NEOM city is a completely new city to be built along the Red Sea coast, over mostly desert, flat land, considerations for the plant's site such as land requirements and proximity to load centers are voided.

Simulations were performed using SAM version 2018.11.11 r4. By using SAM Version 2020.2.29, updated to Revision 3, SSC 242, the same model that was delivering a CF of 95.3%, and an LCOE of 7.84 c kWh^{-1}, returns a CF of 92.4%, and an LCOE of 8.07 c kWh^{-1}. Different results with different versions of SAM are everything but uncommon. Results with evaporative

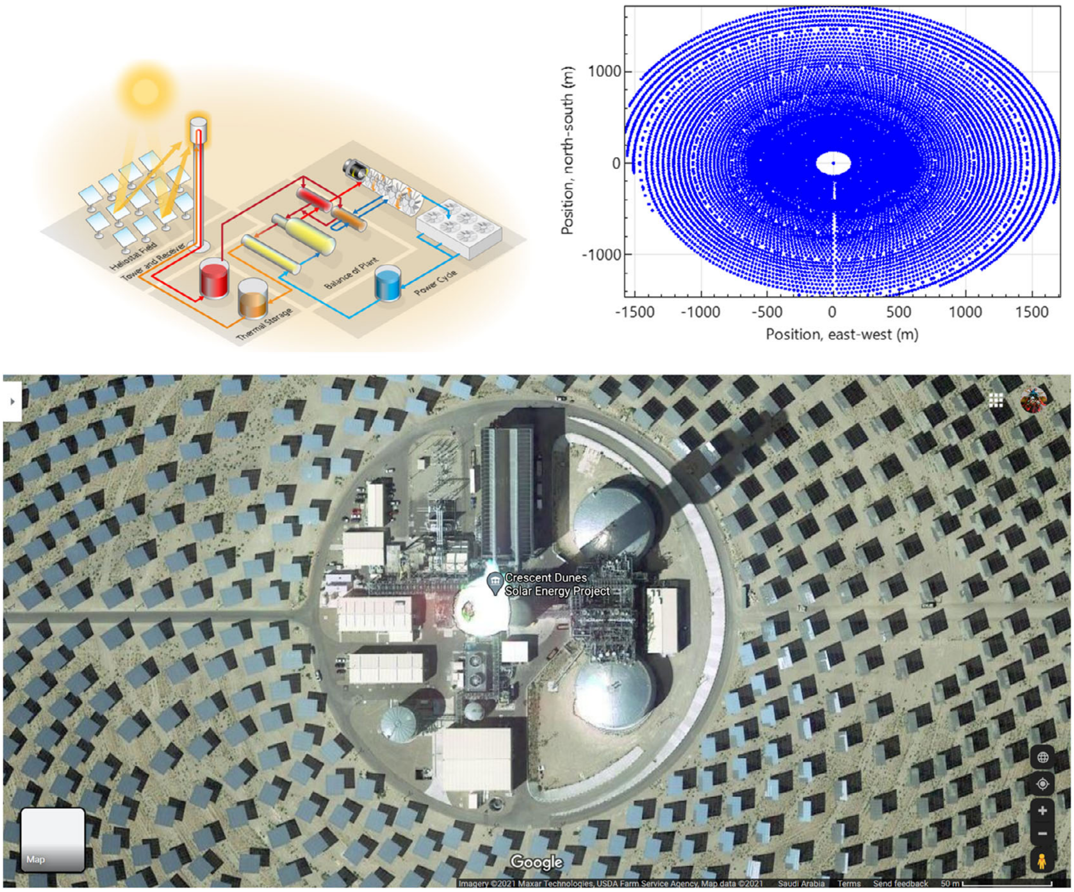

Heliostat Field
Tower and Receiver
Thermal Storage
Balance of Plant
Power Cycle
1000
0
-1000
Position, north-south (m)
-1500
-1000
-500
0
500
1000
1500
Position, east-west (m)
Crescent Dunes Solar Energy Project
Google
Map
Imagery ©2021 Maxar Technologies, USDA Farm Service Agency, Map data ©2021 Saudi Arabia Terms Send feedback 50 m

Figure 2. Top left, scheme of the plant. Credit NREL SAM Software.[15] The heliostat field is circular, with the heliostats placed around the central tower, top right. Bottom, a satellite view (from Google Maps with required attribution: Imagery ©2021 Maxar Technologies, USDA Farm Service Agency, Map Data ©2021.) of the Crescent Dunes plant, with clearly evidenced the central tower, the power block, and the two tanks.

or air cooling with SAM version 2018.11.11 r4 were unreliable. Using SAM Version 2020.2.29, updated to Revision 3, SSC 242, evaporative cooling produces an improvement to a CF of 99.8%, and an LCOE of 7.50 c kWh^{-1}, to a CF of 92.4%, and an LCOE of 8.07 c kWh^{-1}.

3. Results

Simulations were performed by SAM as described before and in refs. [33–35] for the site-specific solar resource and weather parameters. The values of the different model parameters here adopted are reference values for a CSP ST plant of design close to Crescent Dunes, but different TES and size of the solar field. Optimization is shown is only for the number of heliostats.

Simulations were performed using NREL SAM.[15] The ST design permits higher solar concentration. The number of heliostats can be increased without increasing the amount of heat transfer fluid. The molten salt ST model is explained in previous studies.[36–39] A two-tank molten salt TES system is used. Air-cooled, evaporative, and hybrid cooling condensers are considered. Saudi Arabia has no lake or river and thus freshwater use is a concern. This specific design with 20 000 heliostats delivers a 95.3% annual average CF at an LCOE of 7.84 c kWh^{-1}. A 30 years' operation and 15% taxation are considered in the model. By drastically reducing the field of heliostats to 13 500,

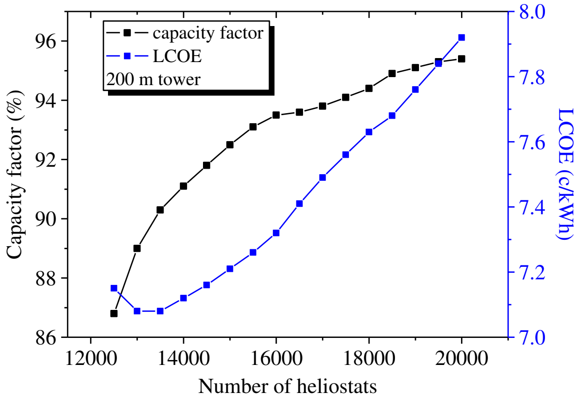


Figure 3. CF and LCOE simulations for dispatchable 100 MW ST.

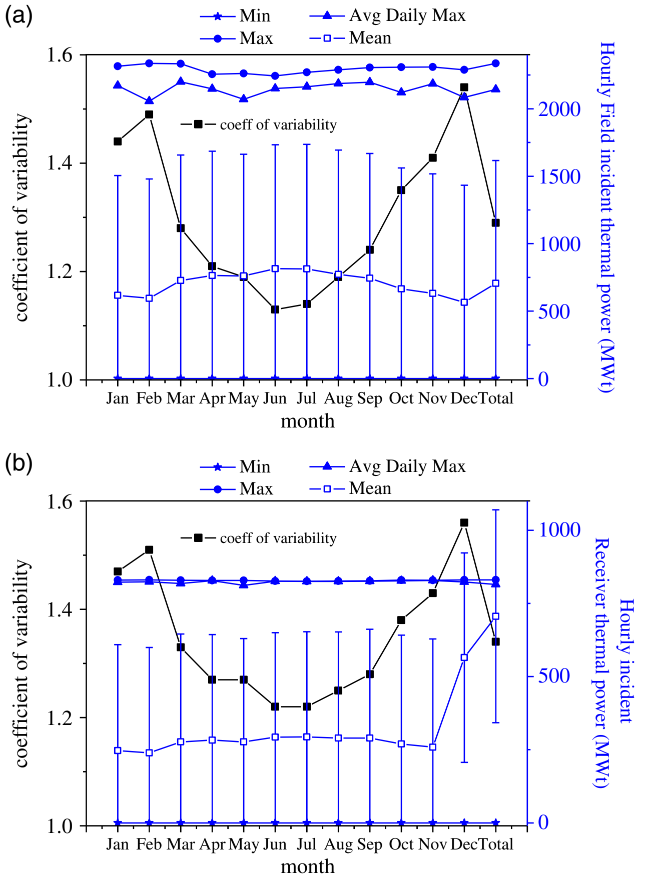


Figure 4. a) Coefficient of variability and the hourly incident field thermal power and b) incident receiver thermal power.

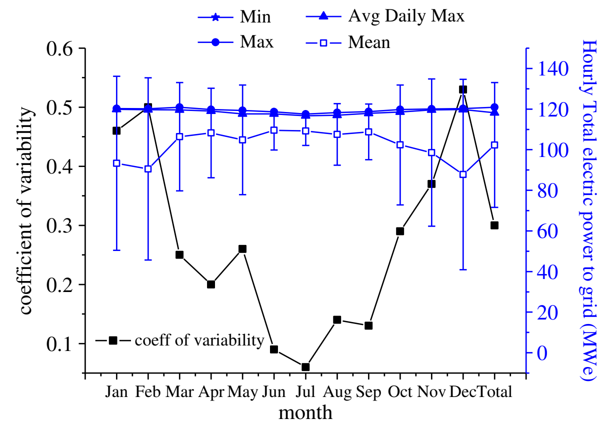


Figure 5. Coefficient of variability and the hourly output of electrical power.

an annual average CF of 90.3% is still delivered at an LCOE of 7.08 c kWh^{-1}.

In **Figure 3** we show the estimated annual CFs and the LCOE versus the number of heliostats, showing that by increasing the solar field the CF increases to a maximum, whereas the LCOE has a minimum.

In **Figure 4** the coefficient of variability of the thermal power at the solar field (a) and the receiver (b) are shown as average and maximum daily values over each month of the typical year. **Figure 5** is the same for electrical power output. It is noted that the coefficient of variability is largely improved for the electric power compared to the thermal input at the solar field and the receiver, which instead reflect similar variability of the solar resource in Figure 1.

Figure 6 describes the performance operation of the 100 MW ST plant here designed with 16 h of energy storage corresponding to 18 500 heliostats, an annual CF of 94.9%, and an LCOE of 7.38 c kWh^{-1}. For this 100 MWe plant, the predicted annual energy (year 1) is 860 284 032 kWh for a CF (year 1) of 94.9%. The annual water usage is 180 641 m^3.

In Figure 6 is the input field thermal power (a), the receiver thermal power (b), the TES charge state thermal power (c), the TES charge and discharged thermal power (d), and the total electrical power (e) to the grid, shown for a typical day of each month of the typical year.

Figure 7 is the cash flow of the project. From a financial perspective, the PPA price (year 1) is 10.18 ¢ kWh^{-1}. The PPA price escalation is 1.00% $year^{-1}$. This delivers a levelized PPA price (nominal) of 11.20 ¢ kWh^{-1} and a levelized PPA price (real) of 8.67 ¢ kWh^{-1}. The LCOE (nominal) is thus 9.92 ¢ kWh^{-1}, and the levelized COE (real) is 7.68 ¢ kWh^{-1}. The net present value is US$112,312,144. The internal rate of return (IRR) is 11.00%. The yearly IRR achieved is 20. The IRR at the end of the project is 13.53%. The net capital cost is US $1,059,170,432 covered with equity of US$463,600,352 and size of debt of US$595,570,048.

4. Discussion

The reliability of the computed costs and performance is everything but easy to assess. SAM is certainly the best tool available for technoeconomic analyses. However, real-world CSP experiences in the United States (Genesis, Mojave, Solana, Crescent Dunes) indicate LCOE in some cases very far from the expected. In the case of Crescent Dunes, LCOEs are also very far from the NREL ATB. It must be added that the United States is the only country in the world to have monthly data of electricity production, and with some uncertainties also information of construction costs, to permit a reliable computation, rather than a subjective guess, of the LCOEs of CSP plants, which by the way also include operation and maintenance costs. For other plants in the Middle East and North Africa region, such as Shams1 and Ouarzazate, there are some subjective estimations of the LCOE but unfortunately no electricity production data, as well as no reliable total construction and operation and maintenance costs to properly compute their LCOE.

Without full transparency of technical and economical parameters of those plants already built, which in many cases we know have suffered from multiple failures and lack of production (Crescent Dunes being one example of the many), the best

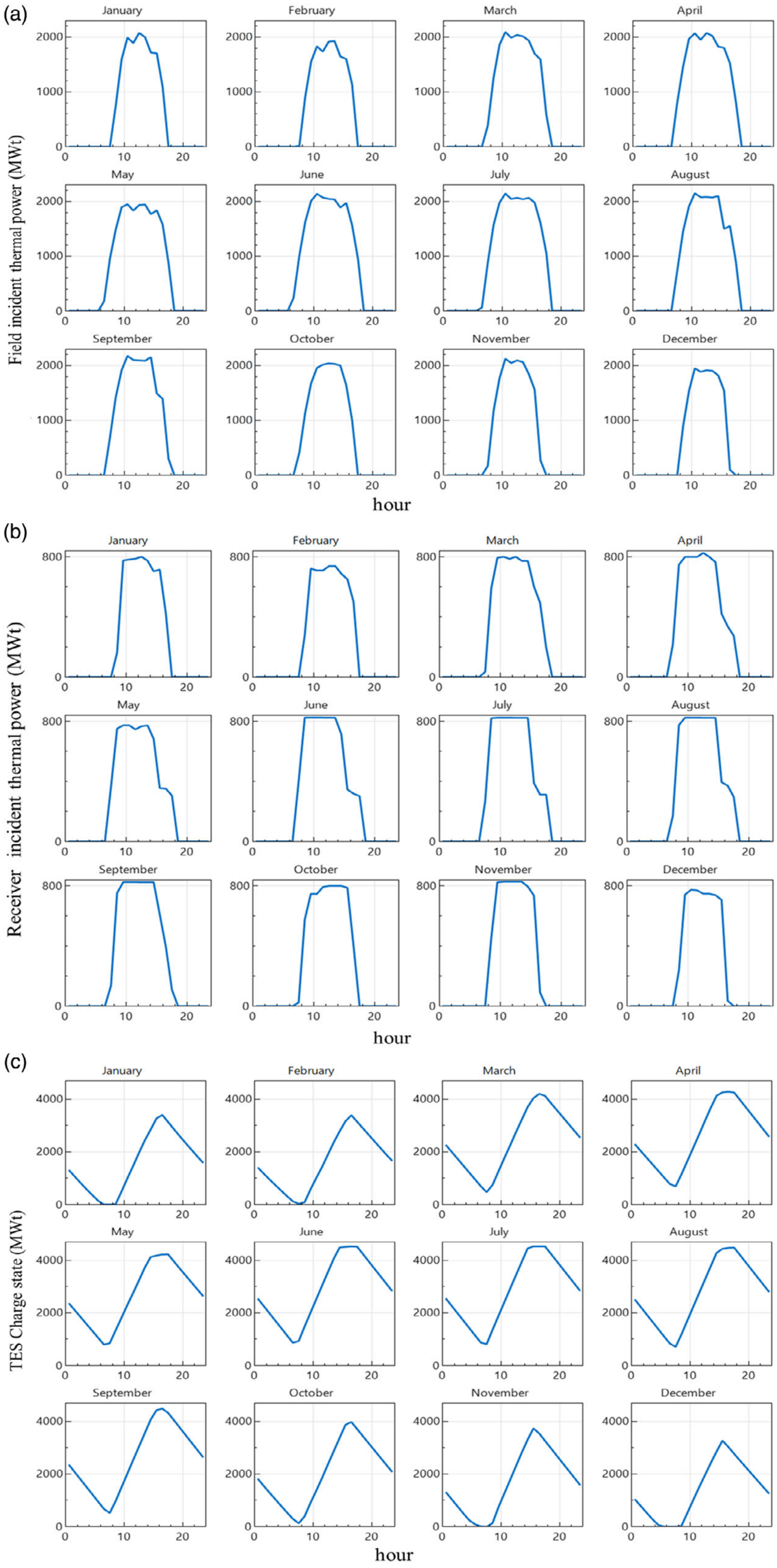


Figure 6. Typical daily variation per month of the a) field incident thermal power, b) receiver thermal power, c) TES charge state, d) TES charge and discharge thermal power, and e) total electric power to the grid.

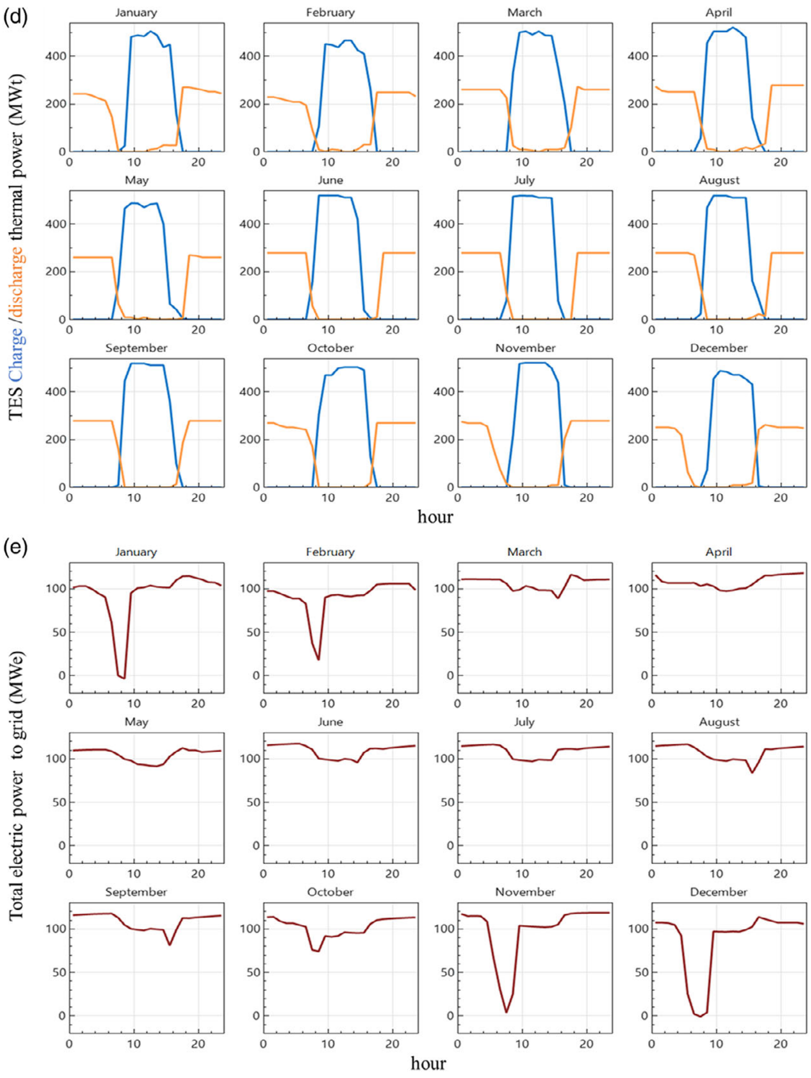


Figure 6. Continued.

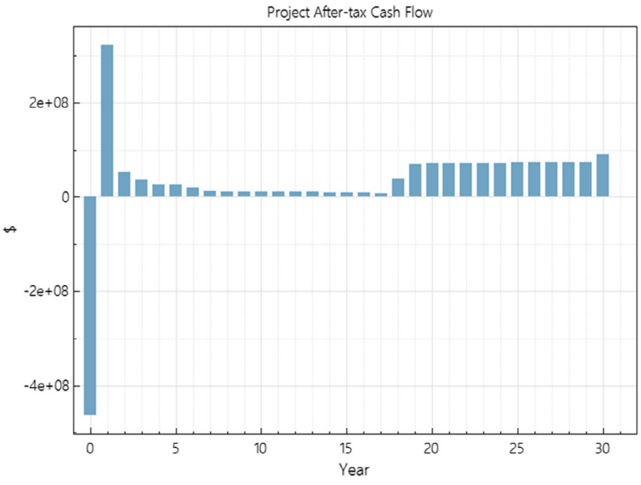


Figure 7. Cash flow of the project.

possible LCOE estimations are the default SAM settings (apart from the different taxation system that can be easily implemented).

The cost of adding more heliostats is demonstrated to be more than compensated for by the increased production of electricity (average CF), the reduction of the standard deviation of the CF, and the reduced LCOE (up to the 13 000–13 500 heliostats of the minimum versus the less than 10 000 heliostats of the Crescent Dunes design for same nominal power). Further increasing the number of heliostats only improves the CF and standard deviation at the price of an increased LCOE.

It is the goal of this work to propose a novel design based on a validated tool rather than to develop a novel computer model. The novelty is the specific design for the specific location to produce electricity continuously, with the key performance parameters being the average CF, the standard deviation of the CF (i.e., the quantity and quality of the electricity produced), and the LCOE.

It is assumed that the readers are familiar with the authoritative NREL assessments in terms of CSP technologies, and are also familiar with the use of NREL SAM, which is the most widely used renewable energy product.

A 95% annual average CF is estimated to be delivered by a CSP ST plant featuring the consolidated, almost 20 years old, Gemasolar design, only with an expanded number of heliostats and expanded TES, and more than that, properly designed components delivering the expected performance and reliability in the specific setting characterized by sand, dust, and extreme temperatures. Poor performance and reliability of components have been an issue of recent constructions of CSP STs with TES. The LCOE of continuously produced electricity is 7.84 c kWh^{-1}, which is much better than that of wind or solar PV plus Li-ion-battery energy storage (without storage, wind energy is unpredictable, and solar energy is intermittent, not continuous). Although the prediction of failure and maintenance, as well as life, will be extremely challenging for the specific technology in the specific location, the operation of a CSP ST with TES is not expected to be any worse than that of solar PV with Li-ion-battery energy storage, which are well known to dramatically suffer from reliability and durability in the specific settings.

The LCOE of PV per kilowatt hour is the lowest between the renewable energy opportunities—projected at 3 c kWh^{-1}. The problem is the external energy storage, which is very expensive (and not that environmentally friendly). Lithium-ion batteries are expensive in general and prohibitive for the specific location because of the sand, dust, and especially the extreme temperatures during summer. Internal energy storage of CSP is much cheaper. CSP with TES permits dispatchability. Once the few technical issues are properly addressed, and a fully functional industrial product is made available, CSP with TES has a much better cost for dispatchable electricity than PV plus batteries—less than 8 c kWh^{-1} in the simulations here performed. However, it must be made clear that there is no competition between different renewable technologies. They must be properly integrated into a renewable energy–only grid to deliver the best performance. For best results, that is, a balanced renewable energy–only grid, at the best price, an AI grid manager will control PV, wind, and CSP generation, CSP storage, and storage by lithium-ion batteries.

Regarding hydrogen, we are considering this opportunity. With PV plus electrolysis, an energy carrier, electricity, is converted into another energy carrier, hydrogen, with an energy conversion efficiency penalty—to be transformed then back to electricity (or other energy forms)—with a further energy conversion efficiency penalty. We should do better. Concentrated solar (CS) with thermochemical hydrogen production is potentially more promising, but apart from the good experiences of the past (e.g., the sulfur–iodine cycle of general electric/general atomic) a lot of work still has to be done. Thus, for now, lithium-ion batteries are a better choice than storage in hydrogen.

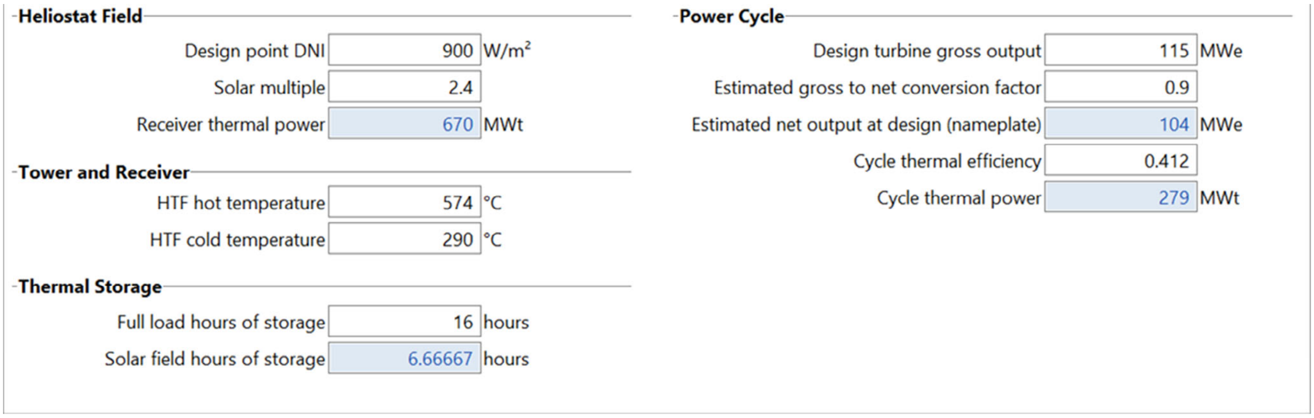
5. Conclusion

CSP with TES as described is not the intended supplier of renewable energy to NEOM city, but only one of the key elements. The renewable energy–only grid needs wind, solar PV, batteries, and CSP, plus an artificial intelligence grid manager.[40]

Without accounting for dispatchability or continuous energy supply, CSP with TES cannot compete with wind and solar PV. However, a renewable energy–only grid cannot exist without dispatchable and continuous supply, as the energy storage by batteries needed otherwise is unaffordable.

Increasing the size of the solar field and adopting many hours of TES of 16 as it was already known at the times of Gemasolar produces a better CF, a better standard deviation of the CF, and a better LCOE, versus the reference technology of the NREL ATB. The design here proposed permits 95% CFs at a cost of less than 8 c kWh^{-1} for continuous electricity supply in NEOM city.

Appendix – SAM Model Details



Heliostat Field

Design point DNI	900	W/m²
Solar multiple	2.4	
Receiver thermal power	670	MWt

Tower and Receiver

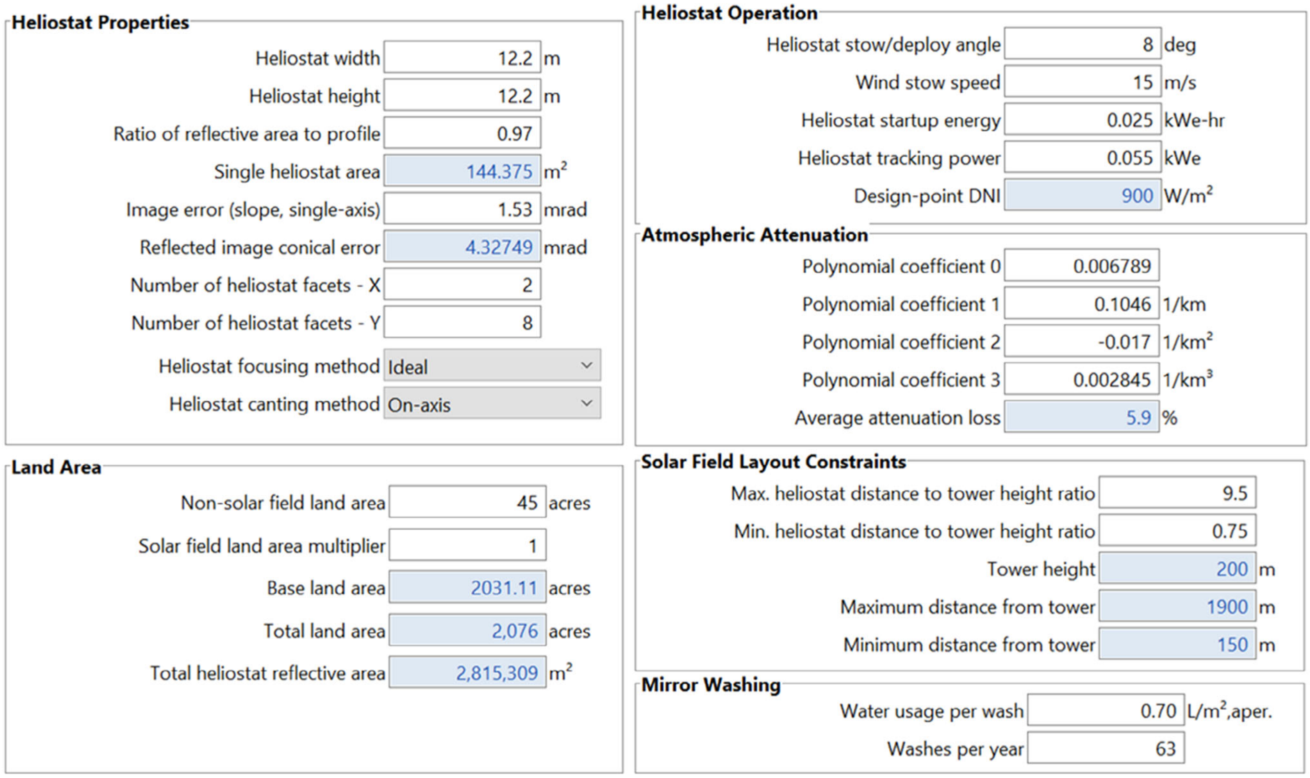
HTF hot temperature	574	°C
HTF cold temperature	290	°C

Thermal Storage

Full load hours of storage	16	hours
Solar field hours of storage	6.66667	hours

Power Cycle

Design turbine gross output	115	MWe
Estimated gross to net conversion factor	0.9	
Estimated net output at design (nameplate)	104	MWe
Cycle thermal efficiency	0.412	
Cycle thermal power	279	MWt



Heliostat Properties

Heliostat width	12.2	m
Heliostat height	12.2	m
Ratio of reflective area to profile	0.97	
Single heliostat area	144.375	m^2
Image error (slope, single-axis)	1.53	mrad
Reflected image conical error	4.32749	mrad
Number of heliostat facets - X	2	
Number of heliostat facets - Y	8	
Heliostat focusing method	Ideal	
Heliostat canting method	On-axis	

Land Area

Non-solar field land area	45	acres
Solar field land area multiplier	1	
Base land area	2031.11	acres
Total land area	2,076	acres
Total heliostat reflective area	2,815,309	m^2

Heliostat Operation

Heliostat stow/deploy angle	8	deg
Wind stow speed	15	m/s
Heliostat startup energy	0.025	kWe-hr
Heliostat tracking power	0.055	kWe
Design-point DNI	900	W/m^2

Atmospheric Attenuation

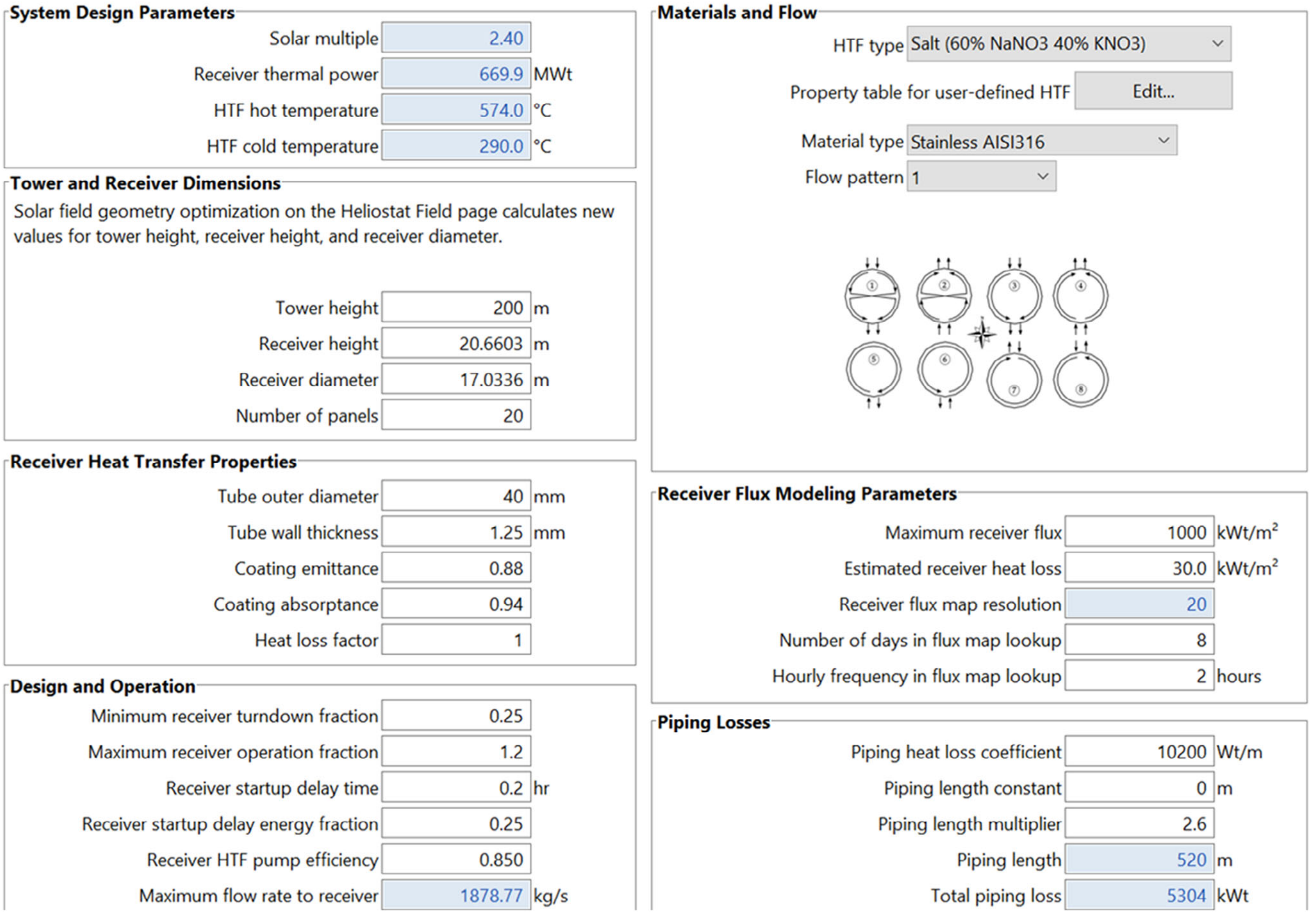
Polynomial coefficient 0	0.006789	
Polynomial coefficient 1	0.1046	1/km
Polynomial coefficient 2	-0.017	$1/km^2$
Polynomial coefficient 3	0.002845	$1/km^3$
Average attenuation loss	5.9	%

Solar Field Layout Constraints

Max. heliostat distance to tower height ratio	9.5	
Min. heliostat distance to tower height ratio	0.75	
Tower height	200	m
Maximum distance from tower	1900	m
Minimum distance from tower	150	m

Mirror Washing

Water usage per wash	0.70	L/m^2,aper.
Washes per year	63	



System Design Parameters

Solar multiple	2.40	
Receiver thermal power	669.9	MWt
HTF hot temperature	574.0	°C
HTF cold temperature	290.0	°C

Tower and Receiver Dimensions

Solar field geometry optimization on the Heliostat Field page calculates new values for tower height, receiver height, and receiver diameter.

Tower height	200	m
Receiver height	20.6603	m
Receiver diameter	17.0336	m
Number of panels	20	

Receiver Heat Transfer Properties

Tube outer diameter	40	mm
Tube wall thickness	1.25	mm
Coating emittance	0.88	
Coating absorptance	0.94	
Heat loss factor	1	

Design and Operation

Minimum receiver turndown fraction	0.25	
Maximum receiver operation fraction	1.2	
Receiver startup delay time	0.2	hr
Receiver startup delay energy fraction	0.25	
Receiver HTF pump efficiency	0.850	
Maximum flow rate to receiver	1878.77	kg/s

Materials and Flow

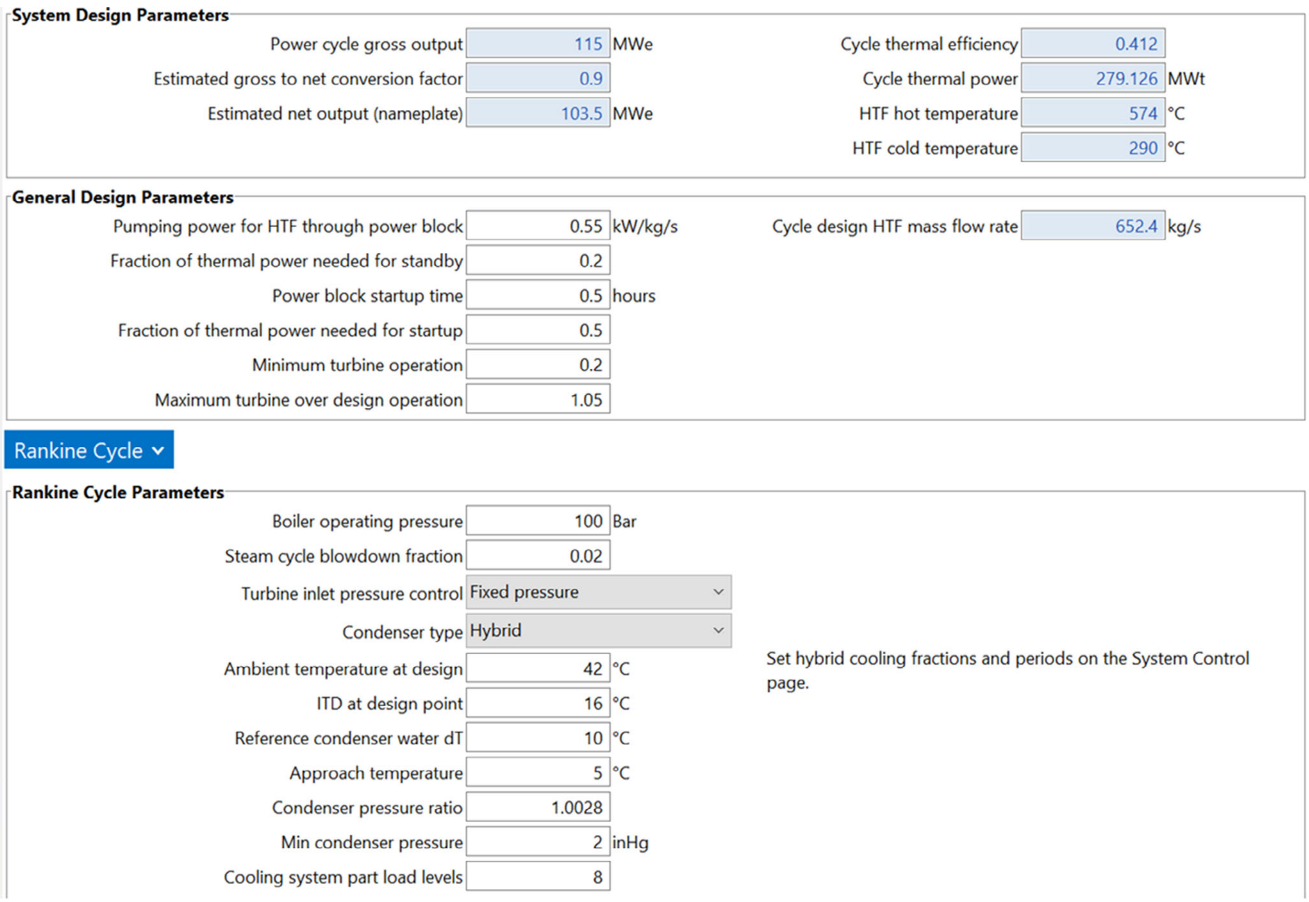
HTF type	Salt (60% NaNO3 40% KNO3)
Property table for user-defined HTF	Edit...
Material type	Stainless AISI316
Flow pattern	1

Receiver Flux Modeling Parameters

Maximum receiver flux	1000	kWt/m^2
Estimated receiver heat loss	30.0	kWt/m^2
Receiver flux map resolution	20	
Number of days in flux map lookup	8	
Hourly frequency in flux map lookup	2	hours

Piping Losses

Piping heat loss coefficient	10200	Wt/m
Piping length constant	0	m
Piping length multiplier	2.6	
Piping length	520	m
Total piping loss	5304	kWt



System Design Parameters

Power cycle gross output 115 MWe
Estimated gross to net conversion factor 0.9
Estimated net output (nameplate) 103.5 MWe
Cycle thermal efficiency 0.412
Cycle thermal power 279.126 MWt
HTF hot temperature 574 °C
HTF cold temperature 290 °C

General Design Parameters

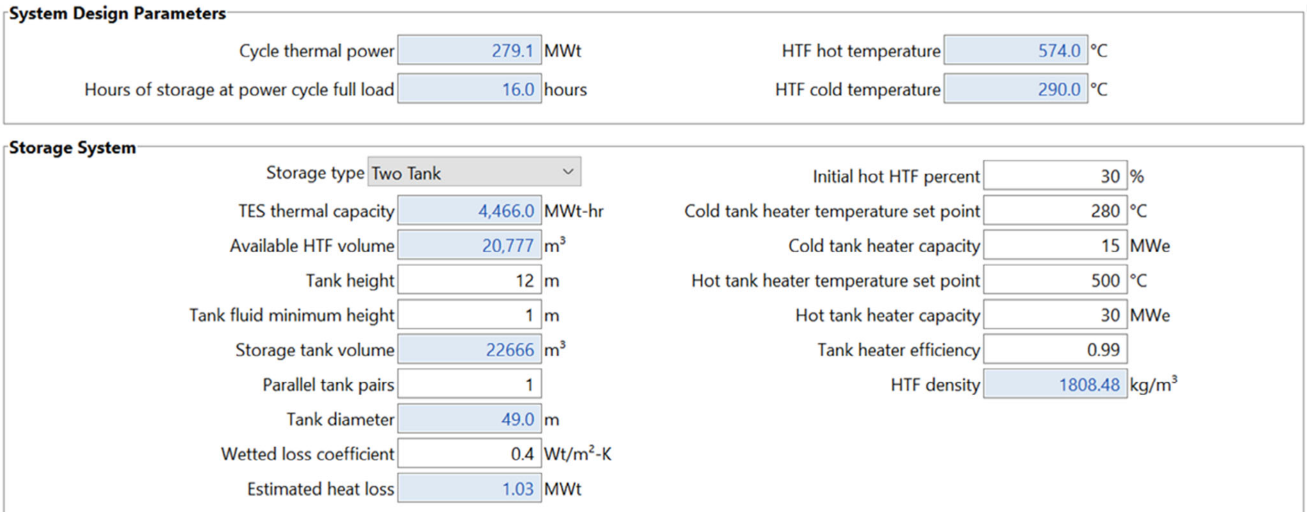
Pumping power for HTF through power block 0.55 kW/kg/s
Fraction of thermal power needed for standby 0.2
Power block startup time 0.5 hours
Fraction of thermal power needed for startup 0.5
Minimum turbine operation 0.2
Maximum turbine over design operation 1.05
Cycle design HTF mass flow rate 652.4 kg/s

Rankine Cycle

Rankine Cycle Parameters

Boiler operating pressure 100 Bar
Steam cycle blowdown fraction 0.02
Turbine inlet pressure control Fixed pressure
Condenser type Hybrid
Ambient temperature at design 42 °C
ITD at design point 16 °C
Reference condenser water dT 10 °C
Approach temperature 5 °C
Condenser pressure ratio 1.0028
Min condenser pressure 2 inHg
Cooling system part load levels 8

Set hybrid cooling fractions and periods on the System Control page.



System Design Parameters

Cycle thermal power 279.1 MWt
Hours of storage at power cycle full load 16.0 hours
HTF hot temperature 574.0 °C
HTF cold temperature 290.0 °C

Storage System

Storage type Two Tank
TES thermal capacity 4,466.0 MWt-hr
Available HTF volume 20,777 m³
Tank height 12 m
Tank fluid minimum height 1 m
Storage tank volume 22666 m³
Parallel tank pairs 1
Tank diameter 49.0 m
Wetted loss coefficient 0.4 Wt/m²-K
Estimated heat loss 1.03 MWt
Initial hot HTF percent 30 %
Cold tank heater temperature set point 280 °C
Cold tank heater capacity 15 MWe
Hot tank heater temperature set point 500 °C
Hot tank heater capacity 30 MWe
Tank heater efficiency 0.99
HTF density 1808.48 kg/m³

Conflict of interest

The authors declare no conflict of interest.

Keywords

concentrated solar power, molten salt, NEOM city, renewable energy, solar towers, thermal energy storage

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